BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

COLUMBIA, SOUTH CAROLINA

HEARING #18-11740 OCTOBER 25, 2018 10:04 A.M.

DN 2018-10-E and ND-2018-27-E:

DUKE ENERGY CAROLINAS and DUKE ENERGY PROGRESS – Allowable Ex Parte Briefing Regarding (A) Docket 2018-10-E - Overview of Duke Energy's Integrated Resource Planning (IRP) process, including an overview of the recently filed DEC IRP and renewable energy purchases under PURPA; and (B) ND-2018-27-E - Hurricane Florence Update

ALLOWABLE EX PARTE BRIEFING

COMMISSION MEMBERS PRESENT: Elliott F. ELAM, Jr., *Vice Chairman*; and COMMISSIONERS Swain E. WHITFIELD, Thomas J. 'Tom' ERVIN, Justin T. WILLIAMS, and G. O'Neal HAMILTON

ADVISOR TO COMMISSION: Joseph Melchers, Esq.
GENERAL COUNSEL

STAFF: Douglas K. Pratt, Technical Advisory Staff; Randy Erskine, Information Technology Staff; Deborah Easterling and Hope Adams, Clerk's Office; Jo Elizabeth M. Wheat, CVR-CM/M-GNSC, Court Reporter

APPEARANCES:

HEATHER SHIRLEY SMITH, ESQUIRE, representing, and *Joel M. Lunsford [General Manager, Construction & Maintenance]* and *Glen A. Snider [Director, IRP and Analytics for the Carolinas]* presenting for **DUKE ENERGY CAROLINAS AND DUKE ENERGY PROGRESS**

JENNY R. PITTMAN, ESQUIRE, designee of the Executive Director of **THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF**

I N D E X

Please note the following inclusions/attachments to the record:

- PowerPoint Presentation Slides (PDF)

P R O C E E D I N G S

VICE CHAIRMAN ELAM: Be seated. Welcome. I'll call this allowable ex parte to order and ask our counsel, Mr. Melchers, to read the docket.

MR. MELCHERS: Thank you, Mr. Chairman.

Commissioners, we're here pursuant to a Notice of Request for Allowable Ex Parte Communication Briefing, requested by Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, that is scheduled for today, October 25th, here in the Commission's hearing room at 10 a.m., and the subject matter to be discussed at the briefing is: A) Overview of Duke Energy's integrated resource planning process, including an overview of the recently filed DEC IRP and renewable energy purchases under PURPA; and B) Hurricane Florence update.

Thank you, Mr. Chairman.

VICE CHAIRMAN ELAM: All right. Thank you, Mr. Melchers.

I'll recognize ORS for an appearance and reading ground rules.

MS. PITTMAN: Thank you, Mr. Vice Chairman.

My name is Jenny Pittman. I'm a staff attorney for the Office of Regulatory Staff, and I'm here today as the designee of our Executive

Director at this allowable ex parte. As the ORS representative, it is my duty to certify the record of this proceeding to the Chief Clerk of the PSC within the next 72 hours and verify that this briefing was conducted in compliance with the provisions of SC Code 58-3-260(C).

The requirements of that statute are, in part, that the allowable ex parte be confined to the subject matter which has been noticed. And, in this case, two issues were noticed: The first was an overview of Duke Energy's integrated resource planning process, including an overview of the recently filed DEC IRP and renewable energy purchases under PURPA, and the second issue is a Hurricane Florence update. I, therefore, ask that the presenters, Commissioners, and Staff all please refrain from discussing any matters not related to these specific topics.

Second, the statute prohibits any participant, Commissioners, or Commission Staff from requesting or giving any commitment, predetermination, or prediction regarding any action by any Commissioner as to any ultimate or penultimate issue which either is or is likely to come before the Commission.

Third, I would ask that the participants, Commissioners, and Staff refrain from referencing any reports, articles, statutes, or documents of any kind, that are not included in today's presentation. A copy of any document which is referenced during the briefing today must be provided to me for inclusion in the record, which I will certify to Ms. Boyd.

Last, everyone in attendance today must read, sign, and return the form which you were given at the door when you came in. This form must be signed by each attendee to certify that the requirements contained in Section 58-3-260(C) have been complied with at this presentation.

Thank you all for your time and attention, and for following all the rules.

Thank you, Mr. Vice Chairman.

VICE CHAIRMAN ELAM: Thank you, Ms. Pittman.

Duke Energy?

MS. SMITH: Good morning, Commission. We appreciate the time that you've given us this morning to present material on these two topics. My name is Heather Shirley Smith and I'm corporate counsel for Duke Energy Progress and Duke Energy Carolinas.

Today we'll hear from Joel Lunsford, who is our General Manager of Construction & Maintenance, who will report on our Hurricane Florence activities. And then we also have with us Glen Snider, who is our Director of IRP and Analytics for the Carolinas.

We will begin, if it pleases the Commission, with Joel Lunsford, to go over our Florence update; and then, after he is done, Glen will come up and provide his portion of the presentation.

VICE CHAIRMAN ELAM: Thank you. Please proceed.

MS. SMITH: With that, here is Joel Lunsford, and I think we're ready to begin.

MR. JOEL M. LUNSFORD [DUKE ENERGY]: [Indicating.]

VICE CHAIRMAN ELAM: You had it.

MR. MELCHERS: Yeah.

MR. JOEL M. LUNSFORD: [Indicating.] Okay. Good. Good, thank you.

Good morning. Pleasure to be in front of the Commissioners again.

So, my intent and purpose today is to give an overview of Duke Energy's restoration efforts after Hurricane Florence.

[Reference: Hurricane Florence Presentation Slide 1]

I'm leading off with a picture of Darlington Motor Speedway, and a lot of trucks there and a lot of staging. One of the points I want to drive home today is, in hurricane restoration, logistics is really the make-and-break. Most people think changing poles and transformers and wires. That's part of it. But having very good logistics – and we are good at it – makes or breaks a storm. It means the difference between a three-day storm and a four-day storm, or a five-day storm and a seven-day storm.

So, just a good visual of the logistics we have of bringing folks together in the mornings and the afternoons.

[Reference: Hurricane Florence Presentation Slide 2]

We've had a hurricane since Hurricane Florence, so I just wanted to remind everybody the path. Remember, Hurricane Florence came in around the Wilmington area, right? It devastated the Wilmington area, then took a hard left-hand turn and came down into the Pee Dee area of South Carolina. Right? So it hit Wilmington on Friday,

then on Saturday – Saturday morning – it came through the Pee Dee area, then it took a hard right-hand turn and went up through the Upstate of South Carolina on Sunday. So just to kind of give everybody a little flavor and memory jog of what happened, since that has been two hurricanes ago.

So what our meteorologist was telling us, "Joel you're not even going to be able to work on Saturday. The wind's going to be blowing too hard." We've got two numbers we go by: One is 40 miles an hour, sustained winds; we won't drive a vehicle when the winds are 40 miles an hour, sustained. The second number is 30 miles an hour, gust; that's the number that you cannot put your aerial device in the air with bucket trucks, right? So what our meteorologist was saying was, "Listen, Saturday's going to be a wash," right? "The winds are going to be too great."

[Reference: Hurricane Florence Presentation Slide 3]

So, Saturday morning, I woke up early. Noticed we had about 73,000 customers out that Saturday morning before the sun came up. That represents about 43 percent of my customers in the Pee Dee area. Almost half were out. But I got to

looking outside, and it was windy, it was breezy and raining, but, to be honest with you, I've been fishing in worse weather. Okay? So we kept an eye. We kept an eye on it. Went outside and started calling folks. "How is it looking in Kingstree?" "How is it looking in Marion?" And so by about 7:30 we made the call, we're working. We're working on Saturday. Right?

So we did a quick check-and-adjust. We already had folks already on standby and just kind of — "Just kind of watch out. We're going to do a check-and-adjust when we wake up." So we worked all day Saturday, and you can see the numbers. We did really good on Saturday.

By Saturday evening, by the time we went to bed, we only had 28,000 customers out. In other words, 68 percent of the original number we had restored by Saturday evening. That's a good lick.

We came in Sunday and worked, and got 85 percent restored. By the time we went to bed Sunday night, we had 11,000 out. And by Monday evening, we had everybody restored except those houses in flooded areas — Nichols was a bad flooded area — except those houses in flooded areas where we had to disconnect the power because of

flooding and safety and working with the counties and the city inspectors.

So, basically, overall, a three-day hurricane. Which is kind of – doesn't seem to go together. Hurricanes usually go five to seven to ten days. That's what Hurricane Matthews was. So South Carolina, as a whole, I think we had a little bit of luck. We didn't get a direct hit. So, basically, a three-day restoration.

[Reference: Hurricane Florence Presentation Slide 4]

So come about Sunday evening, my left flank was getting hit, so – I got not only the Pee Dee area but the Upstate area, too – so had to make provisions, and we made provisions. We said, "Maybe that hurricane comes up." So we left enough folks back in the Upstate, plus we got some resources out of Georgia, some contract resources out of Georgia. Similar numbers. Not quite as bad, because the winds had dissipated by the time it got to the Upstate, right?

So, Sunday morning, woke up in the Upstate and had 8000 out. By Sunday night, we had it 88 percent restored. And then Monday morning, we were left with 800. And basically Monday was a cleanup

day, and we had those folks restored.

So basically a day and a half, maybe two days, in the Upstate. So that was pleasing to me.

[Reference: Hurricane Florence Presentation Slide 5]

Just to give you a little idea of the resources we do and move, you know, I talk about logistics as moving an army. So just in the Pee Dee area, right? Florence, Sumter, Marion, that area along I-95? Just in that area, we had, when we woke up Saturday — now, we moved those people — we moved them Thursday and Friday and rode the hurricane out. We learned that lesson from Matthew, Hurricane Matthew. We can move resources ahead of time, have boots on the ground so that when you do go to work [indicating] — and we saw those numbers come down dramatically on Saturday. Something we learned and something we do. So when we woke up Saturday morning, we already have 1300 line technicians. To give you a little flavor, normally in the Pee Dee we have about 300, native. So we moved a lot of folks from Florida, within Duke Energy, but also a lot of off-system resources as far away as New York, New York State.

So when we woke up Saturday morning, 1300 line

technicians, 400 vegetation – tree-trimming folks, right? – 400 damage assessors/engineers. And then behind the scenes in our call centers – these were not folks in the Pee Dee area, but in our call centers – 2300 folks answering phones and taking information. A good army.

So that was Saturday and Sunday, and remember by Monday we were in the short row. So we had released a lot of folks, and by Monday I only had 900 line technicians, 300 veg., and 200 damage assessors. We sent the rest of the folks on to the Wilmington area, okay? So trying to manage resources and manage our costs.

[Reference: Hurricane Florence Presentation Slide 6]

We talked a little bit about logistics. So if you remember during Hurricane Florence, Governor McMaster ordered a mandatory coastal evacuation, I think all the way from Beaufort County to Horry County. Y'all remember that? So that came about, I believe, on Thursday, maybe two days before the storm. So there were no hotels to be had anywhere from basically the I-95 corridor on into Columbia, on into the Upstate, on into the Asheville/Charlotte area. So one of the things we

did, and it worked great, we worked with the Florence Civic Center to house and feed folks at the Florence Civic Center. So that's a picture of it. Those 1300 folks coming in, you know, to help us in South Carolina, they're sleeping on cots. Right? Most people don't realize that. They're sleeping on cots.

So we housed basically about 1000 people in the Florence Civic Center. We also feed them there. Logistically, it makes a lot of sense; everybody's together at the beginning of the day where you can get them out and working, they can get their orders. They eat breakfast, they take their boxed lunch, they go out and they do their work. They come back in around 9:30, 10 o'clock in the evening. Another good thing to have everybody together, you can do your check-and-adjust and see where you're — what you've got to accomplish, so we can plan overnight for the next day. It works really good.

We also had a similar setup near Marion in an old industrial park that we took over and rented out, and also housed approximately 1000 folks in the Marion area, too, on cots.

So, logistically, it's spartan, but from a

logistical standpoint it's the thing to do and it really did save us, I think, a day. It took a four- or a five-day hurricane and made it into three, just by having logistics and everybody together, being able to feed everybody in the same place. It saves a lot of time.

[Reference: Hurricane Florence Presentation Slide 7]

One of the things we had trouble with was flooding, right? Especially in Nichols. Here's an eye view of Nichols, South Carolina, and the flooding. We learned from Hurricane Matthew that that flooding was the issue, so one of the things I did different this time was created a Flood Director. I can remember that Saturday morning, looking at a young engineer – I say "young"; he's 30 years old, very smart individual – and I said, "Guess what, you're the Flood Director." He goes, "What does that mean?" I go, "I don't know what it means." But I know this: We had issues with flooding in Matthew, right? So I need somebody to keep tabs of the flooding. He took it and ran with it, and it was invaluable. I'll do it every time going forward in hurricane situations

[Reference: Hurricane Florence

Presentation Slide 8]

He would work with the local and state and federal folks, in looking at the flooding, and would make projections. Here's a projection; this is from NOAA, that shows the Little Pee Dee area at Gallivant's Ferry. And we can project two and three and four days in advance when that's going to crest. It helps us logistically on just moving troops and moving crews. If we know we're going to have flooding three days out, we'll get folks in there now to get the power restored and get the lines back up before the flooding hits. Because once the flooding hits, it's cumbersome at best. Okay?

[Reference: Hurricane Florence
Presentation Slide 9]

One of the things he did, too, getting around — I-95 during Hurricane Florence was on-and-off open two or three times. So we have folks staging in Florence and we're trying to go up to the state line area up there, there's a lot of detouring. So every morning he would print out and e-mail to all our leaders what road closures, and even had turn-by-turn directions on how to get from Florence to Marion, for instance, you know? How you do it

normally was out, right? Many roads were out. And that changed — every four hours it would change, right? So he was on top of it. So having that Flood Director — something new I did, but I'm telling you, I think it saved probably a half a day in logistics and moving of troops around.

[Reference: Hurricane Florence Presentation Slide 10]

So one of the things we did — we dabbled this in Matthew and saw the benefit of it — is drones. Using drones to do damage assessment, okay? So let me show you a picture of a flooded area.

[Reference: Hurricane Florence Presentation Slide 11]

So there's a line going down through the trees, and you can see that water. That water is waist-deep. So the line's out. You've got a couple of options, here: You can wait till the water recedes — that might take a week, so that really isn't an option. The other option is to get in a boat, and go and assess the line; the boat comes back out with your damage assessors and you go in. We can do the same thing with a drone.

[Reference: Hurricane Florence Presentation Slide 12]

Instead of taking hours, half a day, it takes about 30 minutes. So actual picture of a drone that flew that line [indicating]. It goes down there and says, "Uh, the only issue is you've got a tree on the line."

So, now, from a logistical and construction standpoint, I know what I need. All I need is really a guy and a chainsaw to go down in a boat, rather than large track equipment or some specialized equipment if I had multiple poles or multiple lines down. Just knowing what you have really helps restore energy. So in this case, the use of drones and technology was tremendous. It was tremendous.

We actually had folks out of Georgia and Florida we brought in. We've got two or three drone pilots within Duke Energy. We had one, two went to Wilmington, but we also asked Georgia Power and Florida Power and those folks, "Do you have any drone pilots?" So they bring them up. It was really good.

[Reference: Hurricane Florence Presentation Slide 13]

I'm going to have to get up and get out of this. There's a movie I want to show you. I love

visuals. So this is a visual of about a 30-second clip of a crew, right, and then some specialized equipment.

[WHEREUPON, the referenced *Video Clip* was presented concurrently with the following narration by Mr. Lunsford, through page 19, line 2.]

So when you say "line crew," you think of somebody in a bucket truck, right? No. We worked in boats, in flooded areas. So there's my four-man line crew working in boats.

We had six to eight boats with us.

[Pause]

And then if you get in situations where you have to change poles and it's too flooded, we've got specialized track equipment like this. We had about six of these pieces of equipment, used them from sunup to sundown. So the conditions were rough.

[Pause]

So, just some visuals of what you go through when you're in flooded areas. You've just got to do something a little different. But if you know you've got flooded areas and you prepare for it, and you have the boats, and you have the

specialized track equipment, when it comes you just check-and-adjust and go with it.

[Reference: Hurricane Florence Presentation Slide 14]

So, external communications is very important. I have a saying, "It's not what you do; it's what people think you do." So we spent a lot of time and effort communicating through social media and through, also, more traditional media, such as TV and radio and print, but we do spend a lot of time. And something we learned in Matthew and something we're doing more of and getting better doing is Facebook. I think that middle one is Tweet, Twitter. I think. I'm not sure.

[Laughter]

Yeah, I'm positive. It's Twitter. And then regular e-mail. Right? So one of the things we do is stay in contact with the local authorities, mayors, commissioners, city managers, that kind of thing. Send out two e-mails every morning. Right? Just an update of what we're doing and where we're at. So, really important to open those lines of communications.

[Reference: Hurricane Florence Presentation Slide 15]

Here's a couple of examples. So, before is on the left, before the storm, just a general "Here's how you be safe in a storm. Here's some of the things you need to do, you know, flashlights and batteries." After the storm, I think it's very important that we'll get media and our corporate communications folks to take pictures, so that folks understand and see the damage, right? People like a visual, so they can see the damage, especially in their neighborhood – in this case, Chesterfield was the area that was hit, Chesterfield County. A lot of flooding, and some trees down, and things like that. So having some visuals really helps folks understand what we do.

[Reference: Hurricane Florence Presentation Slide 16]

Before the storm hit, we do a lot – through the Duke Foundation, we do a lot of money giving and donations. Before the storm hit, we donated $45,000 to the Red Cross in the Pee Dee area. I was proud of that. But also after it hits, once you figure out where it hits, the Duke Foundation also does micro-grants. Here's just an example. I mean, you've got local churches trying to feed folks, right? You've got the Town of Nichols –

right? — where we had all that flooding. Money for dehumidifiers, when they come back to their homes. So Duke Energy Foundation does a lot of micro-grants at a local area to local volunteer organizations that really helps the community. I mean, we're out there helping the community build power lines and getting life back to normal, but then behind the scenes, the Duke Foundation is also supplying monetary grants to folks to help the restoration get along and get folks' life back to normal.

[Reference: Hurricane Florence Presentation Slide 17]

Also, we do volunteer work, Duke Energy. So here on the right is some Duke Energy folks packing lunches, meals for folks who — especially in the Nichols area, whose houses were damaged and they were displaced. Also, afterwards, the Duke Foundation is partnering with DonorsChoose, and this is an effort to supply the schools. So we donate so much, they match it. It goes to school supplies in those counties, in those five counties in the Pee Dee that were hit the hardest, those five school districts. And I'm real proud of that, too.

[Reference: Hurricane Florence Presentation Slide 18]

So, in closing, I would say, again, it was – I think South Carolina dodged a little bit of a bullet. The Wilmington area and New Hanover County and up around Morehead got the brunt of the storm, right? They got kicked around pretty good. We got kissed by the storm. All right? So overall a three-day hurricane. I feel good about our restoration efforts. There's a few things we learned and we'll do different next time, and it's a continual process of learning and improvement.

So, with that, I would love to answer any questions.

VICE CHAIRMAN ELAM: Thank you, Mr. Lunsford. I know we all very much appreciate everything all the crews do in these situations. Everything seems to get back up and running so much faster than it did, as – when we had Hurricane Hugo, how long things took then, that it's been a good learning curve for everybody.

MR. JOEL M. LUNSFORD [DUKE ENERGY]: Yeah, us included. We're continuously doing improvements on how to –

VICE CHAIRMAN ELAM: And we appreciate that

everybody gets better at it.

Commissioners, questions? [Indicating.]

COMMISSIONER WHITFIELD: Thank you, Mr. Chairman.

I've got really just one brief thing. Again, I want to just quickly thank you, just like Vice Chairman Elam did, for bringing us such an informative recap of what happened and what you did and what your response was. We certainly appreciate that.

I do want to – it's more of a comment than a question. We had an allowable ex parte with Duke a few months ago, pre-hurricane, I think late July, probably. And we were made aware of some of the things Duke is doing as a result of their FERC relicensing, with your hydroelectric management system. And I would just note that I know you all, according to that allowable ex parte, are working on long-term solutions, particularly for the Catawba River system, and until those long-term solutions are worked out that was, you know, part of your FERC relicensing, I certainly want to say that in the two storms we've had – Hurricane Florence, Hurricane Michael – that Duke has certainly been very proactive in advance of the

hurricane, such as lowering lake levels, lowering water, and it appears that the management of the flow in all of the reservoirs up and down the Catawba River system were extremely proactive on Duke's part.

MR. JOEL M. LUNSFORD [DUKE ENERGY]: Right, thank you. Our lake management group also does a check-and-adjust after every major event, and they're learning and making it better every time.

COMMISSIONER WHITFIELD: Well, I can certainly say it was noticeable —

MR. JOEL M. LUNSFORD [DUKE ENERGY]: Yes, sir.

COMMISSIONER WHITFIELD: — by a lot of folks out there. And it appeared to be very, very proactive in both of these storms that produced a lot of water.

MR. JOEL M. LUNSFORD [DUKE ENERGY]: Right. So one thing is, you remember Hurricane Florence, we knew about it probably five to seven days. Remember, it came straight across the Atlantic, so there was a lot of time to plan, a very lot of time to plan, so that was a good thing.

COMMISSIONER WHITFIELD: Well, I certainly think the proactiveness was a good thing and protected a lot of property and probably a lot of

lives.

MR. JOEL M. LUNSFORD [DUKE ENERGY]: Absolutely.

COMMISSIONER WHITFIELD: So, thank you, Mr. Chairman.

VICE CHAIRMAN ELAM: Thank you.

Commissioner Hamilton.

COMMISSIONER HAMILTON: Thank you, Mr. Chairman.

Joel, I think what I could say for you today is that we appreciate you taking care of the Pee Dee.

MR. JOEL M. LUNSFORD [DUKE ENERGY]: Yes, sir.

COMMISSIONER HAMILTON: We –

MR. JOEL M. LUNSFORD [DUKE ENERGY]: I'm one of you.

COMMISSIONER HAMILTON: I lived through it with you.

MR. JOEL M. LUNSFORD [DUKE ENERGY]: Yes, sir.

COMMISSIONER HAMILTON: And I know how – I know it was worse, in my opinion, than you told us today, because you were taking care of it and we were kind of watching and living and waiting to see what was going to happen next. I know we sat on our sun porch and watched the top of the trees

twist out on Saturday, when you are working.

MR. JOEL M. LUNSFORD [DUKE ENERGY]: Yes, sir.

COMMISSIONER HAMILTON: It's hard to realize what you were doing and how well you did it, and I want you to know that the folks down there appreciate what you do.

MR. JOEL M. LUNSFORD [DUKE ENERGY]: Thank you. I appreciate your comments.

VICE CHAIRMAN ELAM: Commissioner Ervin?

COMMISSIONER ERVIN: Thank you.

Joel, we really appreciate the tremendous response. I knew that it was good, but I had no idea until I heard your presentation this morning how good. It was an excellent response, shows a lot of foresight and planning. Particularly, you know, what you did with logistics, very impressive. And, you know, you're to be commended. I wish that the ratepayers only knew – I'm sure some of them know, but I wish they all knew what a great response this was, and how you limited the damage and mitigated the problems that could have occurred, and particularly when you come in before the flooding. That's just – that was a brilliant move to get out there before the flood peaks, to cut down on the delay that would've otherwise

followed. So I can't say enough about the response. And we, in the Upstate, had some damage, too. Not nearly as much, but we appreciate the work you did up there, too. We had high winds and, fortunately, not too much flooding, but we had some outages and you took care of them quickly. So we're most grateful for that, and keep up the great work.

MR. JOEL M. LUNSFORD [DUKE ENERGY]: Certainly. Thank you.

VICE CHAIRMAN ELAM: Okay. If there's not anything else, thank you.

COMMISSIONER ERVIN: I have one other question for Joel, and I'll let you go.

MR. JOEL M. LUNSFORD [DUKE ENERGY]: Yes, sir.

COMMISSIONER ERVIN: Governor McMaster has recently appointed a Flood Commission, and I hope that Duke is a part of that commission. Have you all been asked to serve?

MR. JOEL M. LUNSFORD [DUKE ENERGY]: I do not know the answer to that question.

COMMISSIONER ERVIN: Right. Maybe someone can reach out and if not be on the commission, at least volunteer their expertise, because they're going to be meeting soon to talk about issues relating to

outages and so forth. Thank you.

VICE CHAIRMAN ELAM: Okay.

MS. SMITH: At this time, with the Commission's permission, we'll bring up Glen Snider to get to our next presentation.

VICE CHAIRMAN ELAM: Welcome back, Mr. Snider.

MR. GLEN A. SNIDER [DUKE ENERGY]: Good afternoon, Vice Chairman. Appreciate that. A pleasure to be before the Commission this morning.

While we're trying to pull up the presentation, I'm going to say I think I have more slides than I have time, so I'm going to work on a personal development goal of mine, which is brevity, which is not what I normally exceed at. So, we will do my – I'll do my very best to work through these in an expeditious manner.

[Discussion off the record]

[Reference: 2018 IRP & Avoided Cost Presentation Slides 1 ~ 2]

VICE CHAIRMAN ELAM: Okay. Thank you.

MR. GLEN A. SNIDER [DUKE ENERGY]: All right. Thank you, so much.

So, today, I'd like to, you know, real quickly, just go through a little bit of our IRP process overview. I'm going to start real high-

level and just give an indication of the comprehensive nature of the process, then real quickly go through some of the key inputs to the IRP and what we're seeing along each of those key inputs, talk about how we do some of the analytics and select our expansion plan. I have a couple of slides on the takeaways and a couple of graphics. And then I have a few slides at the end that sort of transition into avoided cost, with that issue coming up, and how the IRP is related to avoided cost.

So that's the topics for today's discussion.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 3]

All the materials referenced in here will be referring to the DEC South Carolina IRP filing. And the reason we have a DEP North Carolina filing is because we're about a week and a half out from filing, in South Carolina; however the materials are — we don't expect any material changes to that that was presented in North Carolina. So we'll have that filed here, shortly.

[Reference: 2018 IRP & Avoided Cost Presentation Slides 4 ~ 5]

From a process overview, again, IRP really has

three fundamental tenets to it that we're looking at when we're doing planning: There's an environmental component, a financial component, and a physical reliability.

Environmental, of course, we have always increasingly clean energy as one of our goals. It's driven not just internally but ever-increasing federal and state mandates on air, water, land, that influence the IRP process.

Financial affordability: We look at resource plans and try and minimize impacts on customers by minimizing the revenue requirements associated with the resource plan.

And then physical reliability refers to ensuring we have adequate capacity, not just today but into the future. So we're looking at what's the required reserve margin and making sure we have adequate reserves to deal with abnormal weather, when we have polar vortex type events, or if we have unplanned maintenance requirements, that we have adequate reserves for that.

And all of this takes place under a lot of state and federal regulations, and all of those impact the plan. So you can think of things like tax credits, or environmental regulations, or EPA

requirements, NRC requirements. All of those influence the planning process.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 6]

From a big-picture perspective, you know, what drives the need for new resources in a resource plan? You start at the top with load growth, and as load grows we have to have adequate resources to meet that load growth. That load growth can be mitigated through energy efficiency and DSM; also, behind-the-meter renewables, so rooftop solar, for example, would reduce the load that has to be served by the system. But in addition to load growth, we also have to replace retirements in plant retirements. I mean, our system has been built over the last century and some of those plants, over the planning horizon, are scheduled to be retired, so you have to replace those. We have purchased power contracts that expire that need to be replaced and also create a need.

So all of that load growth plus the retirements and contract expiries create a resource need. We take that resource load balance; we then factor in nonconventional resources, so a lot of our renewable resources, as they come onto the

grid, will reduce the need for either energy or capacity or both. We'll talk about that real quickly. But once we factor that in, we still have a remaining resource gap. And then the plan, the process we go through is to say, "How do we most optimally fill that gap, so that we're building the optimal resource plan going forward?"

[Reference: 2018 IRP & Avoided Cost Presentation Slides 7 ~ 8]

Throughout that process, you know, we go through all these inputs, and I'm going to touch on those ever so briefly, here.

Load growth I showed here both for DEC and DEP. We do have modest – and this is weather-normal peak demand. So what's, you know, what's my peak summer and my peak winter demand growth, across time, and this shows for both of the companies what our peak demand growth is. And there you can see where, for DEP, our peak demand – before considering all the other impacts, you know, that we talked about with renewables and everything else – our gross peak demand is higher in the winter for DEP and it's a little bit higher in the summer for DEC. That doesn't change the fact that we plan for winter for both, because, as I said,

this is before other factors, like solar, that's put to the system that has some ability to meet summer peak but not so much for winter. So we'll get to that later, but from a pure load perspective, we're seeing just under 1 percent growth in peak demand and then a little bit less than that in energy growth.

In talking to our load research group and our forecasting group, you know, some of the tailwinds that are driving this are, you know, a strong economy; we have higher employment in 2017 than was expected; there's growth in number of customers. I think one of our load forecasters said it's the first time in a long time they can remember seeing industrial customer growth in both DEC and DEP simultaneously. We've had record consumer confidence in the last year. So all those have been sort of tailwinds for load growth.

Some of the headwinds have included a shortage of skilled labor that slows down the rate of growth. Employment growth in the rural areas has not been as strong as employment growth in the urban areas; that is slowing growth. There are ongoing concerns about trade and trade policy with China and the EU. As you know, we have a lot of

international trade here in South Carolina. And then, concerns about rising interest rates.

So there's both tailwinds and headwinds that our load forecasting group is always keeping an eye on.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 9]

And in addition to sort of the load forecast, some of the components that go into it that we've talked about in the past, and I won't spend too much time on each of these, but you have three — three of the influences I just picked out here are: energy efficiency — and I've got a few slides I'm going to go through real quickly on energy efficiency, but the company has very robust EE and DSM programs that reduce consumer demand and energy — and that shows, both for DEC and DEP, the reductions in gigawatt-hour sales. On the flipside of that, as we see the electrification of vehicles and transportation sector, that's a lift to demand and energy needs on the system. So we can see the add that that's adding within the load forecast. And then, as we spoke about before, as customer growth and rooftop solar increases, that also declines — you know, produces a downward effect on

the load we have to serve. So that's all shown on the three graphs there, and that's included in that load forecast number that I just provided.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 10]

You know, real quick – and I'm not going to go through – I've got a couple of slides here more as leave-behinds for our energy efficiency and DSM. What I wanted to highlight in these slides, though, is we have a very comprehensive list of energy efficiency programs across the commercial, industrial, residential sectors, low-income programs for low-income communities, that help customers to produce – or, to use their electricity more efficiently. Saves them money on their bills. These programs cover virtually all end-use measures that you can think about, from lighting and HVAC, to weatherization programs that make the home tighter. And, in addition, these programs are developed through extensive stakeholder processes, so we take input – we reach out, have stakeholder meetings, and hear what other stakeholders are doing from a best-practices and a learnings point of view, and we're constantly trying to evolve and improve our energy efficiency programs.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 11]

But I leave in the PowerPoint, both for DEC and DEP, a list of some of our approved programs, and just note that that — well, that's a pretty expansive list. Within each of these programs, there's dozens of particular end uses that we're incenting to be used on a more efficient basis.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 12]

So when you look beyond just the load forecast — I talked about nontraditional or renewable energy resources that are being added to the system. And what I have on this slide is a depiction of what's in both the DEC and DEP 2017 and 2018 Integrated Resource Plans, in terms of our projection of solar resources coming onto the system. I note here that Duke's national leaders in the amount of solar. I think we're second behind California, in the amount of solar being added.

What's really important to note is that we operate our systems — you know, sometimes I hear discussions about North and South Carolina. The system operators operate our system as a whole. So irrespective of where our nuclear, coal, gas, solar

generation is placed, all of this generation is distributed across the entire balancing area of DEC, the entire balancing area of DEP, such that all customers receive the benefit of that carbon-free generation that comes from growing solar on the system. And so these solar projections include activities happening under South Carolina DER programs, as well as House Bill 589 in North Carolina, as well as PURPA solar, company-owned solar. That's the aggregate to that.

One last point I'll point out is, you know, we probably, last year, limited our solar to what was in the current regulations. What you'll see is, while there is a flattening of the solar – I don't know if I have a laser on this [indicating] – but it does continue to increase a little beyond what we had last year. I think we expect to see, even after some of the legislative initiatives end, some modest growth in solar, but certainly not the rate we're seeing here in the early part of the decade.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 13]

And the reason – you know, some of the reason for that, and we point it out in the resource plan, is, as you add more and more of any particular

resource, you get some declining value in what the next increment provides. And so we studied, in the resource plan, that as we add more and more increments of solar, how does that contribute to our peak needs, for example? How much capacity value does a megawatt of solar, 100 megawatts of solar, have on the system? And from a pure capacity point of view, as you add more and more solar, all this slide represents — and I won't go through each number on it — is that the amount that can be counted towards your peak demand declines. And so, in the summer, in particular, when we look at our summer peak and our winter peak, you know, the first increments of solar — I look — I'll pick over here on DEC, on the left. If you look at the first increment of solar, you know, it may be worth — every 100 megawatts may be worth 33 megawatts of peak. But as you add more and more, that goes down to 17 percent. What you'll also see is, because our winter peaks are largely very early in the morning where the sun is just coming up, there's very little, if any, winter-peak capacity value of solar that's added to the system.

So we think it's a valuable resource; it provides a lot of energy for our customers. We

certainly burn less fossil fuel and save on fuel costs. But this just shows that the capacity value continues to decline in the summer, and the fact that there's very little, if any, winter capacity value to the solar resources on our system. So it's something that just points to the need for diversity within your resource plan.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 14]

Moving on to natural gas, which, you know, always gets a lot of discussion and is a key input into the cost of operating a utility system, a big benefit for consumers has been the reduction in natural gas prices due to the continued development of shale gas reserves. And so I'm just going to point out a couple of quick takeaways on this slide, and one is sort of a historical view on the left, and the rise in shale gas on the right that sort of shows how that correlates. But if you look on the left at historic natural gas prices, you'll see a couple of pretty big spikes, and there's always, you know, discussions around volatility in natural gas prices. Well, not only have gas prices gotten lower across time, but they really have become less volatile. Some of those initial spikes

that you see on the left side of the graph were when hurricanes would come into the Gulf of Mexico. That was the only source of supply, and so when that source of supply was endangered, prices would spike and you'd see these price spikes. But as you move further to the right on the graph, what you'll see is, as supply has been diversified across the shale gas regions of Pennsylvania, Ohio, up into the Midwest, hurricanes don't have the impact they used to have when they come into the Gulf of Mexico. So now you're seeing not only lower price levels but you're seeing less volatility in natural gas prices as you diversify your supply basins.

You know, going into this year's IRP, you know — when I took this role a decade ago, I would have never thought I'd have a slide like this where we said, you know, we went out and tested the market and said, "What does a ten-year forward strip of natural gas cost," and we were able to see sub-$3 — $2.85 for the next decade. And it wasn't but seven, eight years ago where gas was — you know, nine years ago, maybe — where it was $9-$10 an MMBtu, and now we're down to under $3, and the market is actually trading that out for a decade from now. So, very significant changes in the

natural gas markets. And as we go through the presentation, we'll see how that has worked its way into our resource plans.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 15]

I also talked about some of our inputs being the need driven by retirements and the need to retire older units and how that impacts your — your resource plan creates a need.

I have here just a quick summary list for both DEC and DEP, our planned retirement dates. Those — you know, for a couple of those, we have plans in place, so for Allen Units 1 through 3, we have commitments and plans in place. Our Asheville units, we're in the process of building a new natural gas combined-cycle at our Asheville site. When that comes on-line, we'll be retiring the coal plant at Asheville. For the other units beyond that, we're putting in placeholders in the resource plan that are consistent with our depreciation studies that are used within the rate-case context. So as we get new depreciation studies — and what we've seen lately is an acceleration in the industry in the coal plant retirements, you know, partly driven by the discussion we just had on

natural gas as it becomes a more viable and lower-cost alternative, you're seeing lower capacity factors, lower — or utilization rates on your coal plants, so, and an expectation that those are likely to retire a little earlier than maybe we thought five, six, or seven years ago. So the retirements in the later part of the plan are consistent with those assumptions that are in our rate cases.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 16]

Nuclear resources: You know, in past years, we have assumed that at the end of our license life, our nuclear resources would retire. Of course, Duke Energy is one of the largest nuclear operators in the country. And so we're always looking at the economics of our nuclear plants and what makes sense in terms of continued operation.

You know, in last year's IRP, 2017, we had a sensitivity that said, "Well, what if we were to get the 20-year license, subsequent license renewal?" Showed that as a sensitivity case, but in the base case we had the plants retiring. We've seen a lot of progress both internally and as an industry in subsequent license renewal, in terms of

the NRC defining the process for subsequent license renewal, what that's going to look like. We feel like all of our facilities are excellent-run nuclear facilities that are good candidates for potential subsequent license renewal. We've stood up an organization that's working on that right now, evaluating each of those facilities. And so while we don't have that subsequent license renewal in place at this time, we think, for planning purposes, it made sense to make that part of our base case now and have the sensitivity be "What if something changes, going forward, and you don't get it?" So we still run a sensitivity where we don't get a subsequent license renewal, but we see the industry progress, you know, moving in a direction where we think it's important to make that our base case.

My last bullet there just talks about, in the long run, you know, longer term and into the next decade, small modular reactors represent a potential development in nuclear that could be a game changer in terms of, you know, time to build, construction risk, size, the ability to load-follow, a lot of things that I know we're all too familiar with. And so we see that as more of a

long-term potential that we're starting to evaluate in the longer term for the IRP.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 17]

Battery storage always gets a lot of discussion these days as cost for battery storage continues to decline. It's a very complex topic because of — you know, everybody who — I've talked to a lot of people about batteries and everyone has a different definition of what a battery is and what a battery can do. You know, we think about it from a very multifaceted perspective.

We did include approximately 290 megawatts of batteries in the IRP as placeholders to — as we look at various projects, we think there is a potential for batteries. One of the important things for batteries: How do you get the most value out of it for consumers? And, you know, batteries can have benefits at the distribution level, at the transmission level, and at the generation level, if deployed appropriately and controlled appropriately.

And so what we're looking at and studying right now, and developing further models to evaluate — and I'm going to talk about that in a

minute – is how do you deploy these batteries on the grid as a grid type battery? How do you control them appropriately so you can get the most value? We've had – some of the initial projects we're looking at are able to – for example, there's a project up in Hot Springs that we're looking at where you can deploy a battery instead of having to build a second distribution line through the mountains, with very difficult right-of-way, very expensive to construct because you're in mountainous regions. And it would be there predominantly for redundancy, to improve reliability for the City of Hot Springs. Well, how can I maybe now deploy a battery, such that if I do have some temporary outages on the one primary line that goes up there, I can use the battery while I'm restoring that outage or doing some quick work at the substation? And then, when that battery is not in use for a transmission purpose, can I use that to do generation load-following? And so I'm stacking benefits of a distribution battery with generation benefits, as well.

And so that's – you know, as this technology emerges, it has – it has its limitations; it's not the answer to everything, but it also has a lot of

promise for benefits on the transmission, distribution, and generation system. And so that's something the company is actively pursuing in both initial projects but also developing enhanced model capabilities, which is what I mention on the next slide.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 18]

We're coining this term "ISOP," Integrated System & Operations Planning, where we're trying to develop modeling and modeling frameworks and business practices that better integrate transmission, distribution, generation planning to allow for the quantification of some of these benefits.

You know, the toolsets that we're trying to develop, for example, are trying to get down to much more granular levels from two perspectives: One is a geographic perspective. I think I've been before this Commission before and we've had some debate with other stakeholders around, you know, what are the benefits of distributed resources, whether that's solar or batteries, and it's very location-specific. You know, you put load or generation in one region and it may present a cost,

put it in another region and it may present a benefit. So how do we get more granular in our modeling, down to more specific locational?

Batteries, a lot of where their potential lies is not just at the hourly level but what it can do minute-to-minute, second-to-second, on the grid. All of our models to date are largely hourly models, which is, you know, already pretty granular when you think we're planning out a 15-year IRP and we do models that run out as far as 40 or 50 years, we're looking at every hour of every year into that time horizon. Now we're asking our analytics group "How do we start to go sub-hourly? How do we start looking at the benefits that happen, you know, on a 10-minute increment instead of a one-hour increment?" That's a big lift, but it's something the industry is moving towards and we're moving towards, as well, so that's all part of our Integrated System & Operations Planning initiative.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 19]

One last point I wanted to make on DEP: We talked about retirements. I did mention in the initial overview, one of the other things that drives the need is an expiration of purchased power

contracts. So DEP has a significant amount of purchased power contracts that are expiring in the beginning of, you know, 2020 or 2021. And so, rather than just negotiating those one at a time for a renewal or an extension of those contracts, we wanted to make sure that we were being prudent on behalf of our customers and that we're getting the lowest possible price. So we went out for a targeted market solicitation and said, "Hey, there's multiple providers out there. You've been providing reliable service, but there's a few others. Let's go out and make sure we're creating a competitive environment, getting bids in, to make sure we're renewing these contracts at the lowest possible price," and if the price is too high, maybe there's an opportunity to switch to a lower-cost provider." We're in the middle of that process right now, and so next year's IRP will reflect – we put a placeholder in this year's IRP that had generic extensions of those contracts to sort of reflect the fact that we think, you know, we'll be able to get reliable supply from the marketplace. Once we get those contracts executed over the next year, we'll put those in the IRP.

[Reference: 2018 IRP & Avoided Cost

Presentation Slides 20 ~ 21]

And in the interest of time, I'm certainly not going to try and go through this slide in a great deal of detail; it's a very busy slide. But I just wanted to give a feel for the comprehensive nature of planning, just how detailed and robust our plans are. We don't just pick a plan under one set of assumptions and say, under this one of assumptions, this plan works. We actually look at all the different drivers — that's the little arrows on the left — and we say, "Let's flex each one of those and see how the portfolio would change." And when you flex those and say, "Boy, you know, under a high-carbon or a low-gas or a high-gas or under a high-energy-efficiency, my portfolio would change," you get lots of different portfolios. We grouped those this year into about seven different portfolios that had different levels of resources in them, different amounts of CTs, CCs, solar, energy efficiency. And we looked at each of those portfolios, then, under different futures. So we said, "Now that we have these seven portfolios, how do we determine which one is the optimal resource plan to include as a base-case resource plan?" And we looked at each of those under a different amount

of — differing gas prices, different carbon assumptions — a no-carbon assumption, a mid-carbon, a high-carbon. We looked at it under different CapEx, what if the cost of capital or the cost of technologies change, higher or lower, how would that influence the plan?

When we looked at all those, we said our — which portfolio seemed to be the most robust under an uncertain future, because one thing about plans is you're going to be wrong, but are you really picking a plan that's robust, that looks good under different futures. And so we go through an extensive process to look at multiple portfolios under multiple futures, and try and pick the plan, a base plan, that performed the best. And we present two plans as base plans in the IRP — one in a carbon-constrained future and one in a non-carbon-constrained future — and present those in the resource plan.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 22]

Again, a little bit busy but I do think there's a lot of information on it. This is one of — a good visual that I like to show when I talk about our base-case plan. This shows a base-case

plan for DEC and for DEP. And, just real quickly, the way to look at that graph is, the blue bars going up represent new resources that are projected to be needed across time; the red bars going down are the projected retirements that we spoke about, or contract expiries; the green line represents the cumulative amount of nameplate solar being added to the plan. And so, you're seeing the additions and the subtractions, along with the solar growth. I did note in the comments here that DEP, given its load growth plus retirements, has a little bit more need than DEC, so we see, you know, a few more blue bars in the DEP than in the DEC.

So that's a one-picture-tells-the-whole-story for the — in terms of the amount of resources that are needed across time, as well as those being retired.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 23]

That's just from sort of an asset-by-asset basis of what's being added, but if you want to look at it more from a — and, again, another picture-worth-1000-words slide on 23 is, in a carbon-constrained base case, the first — what I did for both DEP and DEC is I looked at what's our

capacity resource mix today? What's our diverse portfolio look like? And, again, this is from an installed capacity; the next slide I'll talk about the energy. So this is just the megawatt nameplate of each resource on the ground. Where are we in 2019? At the end of the plan, where will we be? And then the arrows pointing down to the bottom graph point out what additions – of the resources that are changed, what's the pie chart of the resources that are being added? You know, a lot of times I'll have stakeholders think that we're going to change the entire 20,000 megawatts of DEP in the next decade, and that's simply not the nature of our portfolio. These are 40-, 50-, and 60-year assets. Some of our hydro assets are 100 years old. They will evolve over time, over the next decade. So for those resources that are being added over the 15-year planning horizon, that bottom pie chart shows how that capacity mix has changed.

So what you can see is, obviously, you know, one of our key assets – and it continues to be – is our nuclear, which is sort of the base-load round-the-clock generation. That amount of nameplate nuclear stays constant pretty much, except for some

small uprates across time. Well, what you're seeing is, as we retire coal and as we have load growth, it creates the need for new generation that, in DEP, is largely being met by natural gas and renewables and DSM. And the same picture for DEC, the reason there's more renewables is we already have more renewables on the ground today in DEP than DEC, so there's a little less growth in renewables in DEP as compared to DEC.

And while this is a good picture of installed capacity, it doesn't really tell the story of energy. Where does the energy come from? You know, where — you know, as we consume electricity, what's the source of the megawatt-hours? Because all these resources run at different utilization rates.

So if I flip over quickly to slide 24 —

[Reference: 2018 IRP & Avoided Cost Presentation Slide 24]

— I presented the energy mix for both companies combined, to just say between the two, DEC and DEP, and the fact that we use the Joint Dispatch Agreement to send energy back and forth, one to another, on a non-firm basis, what's their collective use of energy? And I like to do this

from both a historical perspective, where we are today, and where we might be in 15 years — because a lot of times, when you're in the here-and-the-now, it seems like things are moving slow, but when you step back and take this historical perspective, it shows a pretty dramatic shift in how electricity has been produced at Duke Energy Progress and Duke Energy Carolinas.

If you look, the graph on the left — and let's just focus on the top — that's the total energy mix on the top. Fifteen years back, we were half nuclear generation and half coal, with just a sliver of hydro and gas. That was — you know, I probably could've made that ten years ago and it wouldn't have looked much different. You come to today, and look how much coal has been reduced. And it's been replaced by natural gas, DSM, EE, and renewables, both CTs and combined-cycle. And if you fast-forward 15 years to the end of the plan, you see that that shift in energy production continues to move in that direction, and we become less dependent on coal and more on natural gas, renewables, and energy efficiency.

To highlight that, I put in the three bottom charts. You know, in light of the discussion

around subsequent license renewal, if you think about nuclear generation provides about half the electricity for Duke's customers, and it has and in the pricing horizon it's projected to continue to do that, then you say, "Well, what's happening to the part of the portfolio you can actually effectuate?" And so if you strip nuclear out, the bottom graph shows the remaining energy consumption. And so that just continues to highlight the point I made earlier of, on a non-nuclear basis, you can see where, you know, just a little over a decade ago, you know, it was virtually all coal. And now look at non-nuclear generation, where we are today. You know, you have a very diverse resource mix that provides a lot of benefit in that diversity for customers, and then that diversity is continued – you know, is projected to continue into the future.

And so I thought that's just an interesting way to look at it both from a historical and a forward-looking perspective, to really see the pace of change. And at times I think a lot of the discussion around – that I have with stakeholders, really isn't a disagreement about what; it's more a disagreement about when, and what's the appropriate

time for some of this change.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 25]

So, I think we're running a little over. Most of the takeaways I think we've already spoken about, as I've walked through that, so I'm going to go through these, you know, pretty quick.

First need: Again, in DEP, we have the ongoing RFP; we have a more immediate need. In DEC, we don't have a need for capacity until 2028, a little bit later in the planning horizon.

Nuclear: We spoke extensively just a moment ago about providing 50 percent of — approximately, 50 percent of the energy, and the transition and the importance of that. So working toward subsequent license renewal is going to be a big initiative for the company, moving forward.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 26]

Solar energy: Again, national leaders. Significant amount of solar energy in the ground today and we project it to grow very significantly over the next five and six years.

Part of the ability to sustain that long-term is going to be the deployment of batteries —

predominately, the T&D asset, but also on the generation side. Those batteries will be able to better integrate some of the intermittent generation coming onto the system.

We talked about the development of the – you know, the need to develop further models to help us evaluate these batteries.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 27]

You know, in summary, you know, solar growing from approximately 2700 megawatts in DEC and 1650 of additional megawatts coming on between that, EE, and DSM. We have 3500 megawatts in DEC and 5900 in DEP of new natural gas technologies projected in the plan.

I spoke a couple of times about the subsequent license renewal and the importance of that, especially at the latter portion of the plan, and the deployment of batteries.

And the result of all of that, and the picture in the pie charts, is that we have a very diverse resource portfolio. It gives us a lot of flexibility. We can dispatch units back and forth, appropriately. So it really does provide a lot of stability in price for customers.

[Reference: 2018 IRP & Avoided Cost Presentation Slides 28 ~ 29]

I'm not sure I'm winning on my approach at brevity here, so I'm going to try to move through the PURPA discussion a little bit quicker.

The IRP – and I did listen in to the stakeholder meeting on Tuesday – you know, it does very much relate to PURPA avoided cost. And I'm not going to read all the bullets on here. I think y'all are very familiar with the federal Public Utility Regulatory Policies Act. It applies, when it comes to renewables, to 80 megawatt renewables, who have a right to put their power to the system. It creates an obligation for customers to pay for that power.

You know, one of the things, as we go through PURPA, that we always focus on – I start with it, I'll end with that – is, you know, at the very heart of PURPA is this indifference principle, sometimes called a but-for principle, and it really does require customers to pay no more for renewable generation than what they would otherwise have paid, had that generation been produced by more traditional sources. And so it's that but-for principle that we always try to keep in mind when

we develop our avoided-cost pricing and methodology.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 30]

Here in the Carolinas – historically, both in South Carolina and North Carolina – we use what's called the peaker method. Simply put, the peaker method looks at the two biggest constructs of the value of a QF renewable, which is capacity and energy, and it says energy is the marginal value of energy from your whole system. But if you only compensated PURPA participants for the marginal energy, they would not be getting compensated for the capacity value they add, if they add capacity value. To price capacity, since you're giving the highest marginal value of the system, you then say, "Well, what's your marginal capacity?" And that's a peaker. In terms of since the peaker itself doesn't produce a lot of energy value, you just give the peaker its capacity value within the construct of PURPA, so you say, "What's the carry cost of a peaker?" You add to that the marginal cost of energy. The two is fair compensation for a QF.

[Reference: 2018 IRP & Avoided Cost

Presentation Slide 31]

But there are some, you know, some caveats to that. And, you know, this assumes, for example, that you have a need for capacity. So when you're calculating, "Should I get a peaker carrying costs," you only would want to do that starting with the year that the company actually had a capacity need. You don't want to be paying for capacity when you don't have a capacity need.

As I think a speaker on Tuesday said, you know, we always have an energy need. We produce energy 8760 — eight thousand seven hundred sixty — hours a year, so what's the value of that energy? That's where we look at that marginal value of energy. And, you know, to do that, we simply run our system — that base production plan that came out of the IRP that said, "This is what the system looks like for the next 10 or 15 years. How much is that marginal energy worth?" To do that, we simply say, "If I had a free 100 megawatts and I put that in the system, how much money would I save on a dollar and a dollar-per-megawatt-hour basis?" That then can be used to derive the rate or the value of energy for QFs. Capacity then says, "Well, when is my next need? At first need, what's

the carry cost of a peaker?" Since I'm giving the highest marginal energy, I give a lower capacity, and then you put that into your rate calculations.

So that's — we use the IRP as the basis for calculating avoided-cost value, and it reflects all of those variables that we just — that I just spent too long talking about, in terms of gas prices and coal prices and how much of the various resources you have on the system. All of that influences what is the but-for value that would be created by a QF provider. And so the companies use that IRP as their basis for calculating that, and that's how we come up with our calculation.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 32]

I think we've covered a lot of the points on Slide 32. You know, PURPA should not require customers to pay capacity unless they have a need. First capacity need for DEC's 2028, 2020 for DEP.

We use the no-carbon base case, since we don't have carbon regulation in place now. You don't want to pay in advance for something that may or may not happen in the future. Carbon seems to be one of those things that is two years away, for the last decade and a half.

We talked about how we do the calculation; we just add 100 megawatts of no-cost generation and say, "How much production cost value does that save?" That's how we produce that energy savings.

The last bullet there, I point out, you know, we talked about where gas prices have been and how they've declined. That really speaks to sort of the risk of having too long of a term for fixed-price contracts under PURPA. If you set those contracts ten years ago, let's say you set them for 20 years when gas was $10, you're now only halfway into those contracts and gas is $2 but you're still paying as though gas was $10. So it really does help quantify the risk that could be involved if you go too long of a term on those PURPA contracts.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 33]

I'll end with this slide. You know, we certainly believe that QF resources, you know, do produce energy value for customers, but, depending on the nature of the resource, they may or may not produce capacity value. As we've seen, and I showed earlier in our IRPs, we plan more for winter peaks that are early morning, so, for solar, in particular, we don't see a lot of capacity value.

While we do see energy value, we don't see the capacity value.

They do have — if QFs are deployed at the distribution level and deployed in the appropriate volumes, they have the potential to avoid transmission line losses. Again, the need to get more specific on your regional modeling is what some utilities are seeing, what we are starting to see in DEP, is, if you put too many resources on a particular distribution circuit, you end up flowing back onto your transmission system and what's called backfeeding or going back onto the transmission system, so then you wouldn't be avoiding line losses. So, again, the need to get more specific in the regional modeling.

And the last point I'll make is, you know, one of the other considerations that we're starting to look at and model is we don't only have to balance the system over a 10- and 15-year horizon; we have to balance it minute to minute, hour to hour. And when you have intermittent resources in large numbers, that can tend to increase the amount of volatility in your minute-to-minute, hour-to-hour load, which means you have to hold back additional operating reserves to deal with that, so that you

have enough generation that can go up or down to deal with the intermittent nature of the resource. And holding that back can create a slight cost that offsets some of the energy value. So you have a fuel savings, but that fuel savings can, at times, be somewhat mitigated a little bit by this integration cost that can be caused by intermittent resources.

That was a really quick — I was sort of looking at the clock. I little bit rushed through the PURPA segment, but I just wanted to have that on the end to sort of show how we use the IRP as the foundation, how robust the IRP is, and then we use that IRP base case as the foundation for calculating the value or that but-for principal.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 34]

And, you know, the last bullet point on slide 34, I really just tried to drive home the point that, as I've been the avoided-cost witness for the company over the years, I've seen, you know, hundreds and hundreds and hundreds of pages of testimony on this, and a lot of debate amongst stakeholders. But the guiding star for me has always been this indifference principle. If I step

back from the minutia and the detail, are customers paying approximately the same thing they would pay if that generation was being generated by traditional generators? And if, you know, if you can use that as the guiding star, I think it helps cut through a lot of the details that end up getting debated amongst the stakeholders.

So with that, I apologize for running over a little bit, and I'd be happy to take any questions the Commission might have.

VICE CHAIRMAN ELAM: Okay. We appreciate the presentation.

Commissioners? Commissioner Whitfield?

COMMISSIONER WHITFIELD: Thank you, Mr. Chairman.

Mr. Snider, good to have you with us again. You covered a lot of territory, several different areas, and I think you did improve on your brevity a little bit, but it was very informative and you did, again, cover a lot of ground – PURPA and a lot of other areas. But I'm going to home in just for one quick question, specifically, on the assets in DEC and DEP for just a second. If you could get to Slide 22 right quick?

MR. GLEN A. SNIDER: Sure.

[Reference: 2018 IRP & Avoided Cost Presentation Slide 22]

Is this the one you're looking for?

COMMISSIONER WHITFIELD: That's it. And on my paperwork here, I really have to cheat a little bit, because it's kind of small. But on the DEP one, you have – I'm looking in our current timeframe, 2018. Obviously, you're adding a good bit of generation there. Looks like Asheville combined-cycle? Am I reading that right? It's pretty small on mine.

MR. GLEN A. SNIDER [DUKE ENERGY]: Yes, that's the 2019 combined-cycle. I apologize for how small that did come out, because I can barely read it myself.

COMMISSIONER WHITFIELD: Right. And so that generation up in the western side of the – is actually going to DEP and not DEC.

MR. GLEN A. SNIDER: That is correct.

COMMISSIONER WHITFIELD: From that combined-cycle. And that's obviously – well, looks like a pretty large – I can read maybe 500 megawatts? I can't quite see the graph.

MR. GLEN A. SNIDER: You're doing a great job. It's 560 megawatts. It's two one-by-one 280

megawatt combined-cycles.

COMMISSIONER WHITFIELD: Well, I just guessed. That line looks like it's halfway between zero and 1000 to me. So that is going to DEP, as you're saying here, and being added onto its – the Duke Energy Progress – generation asset, and not DEC, right?

MR. GLEN A. SNIDER [DUKE ENERGY]: That is correct. Duke Energy Progress has two balancing areas. They have a distinct balancing area in the east, which is the predominant amount of their load. So out of a 15,000 megawatt system, about 13,900 of it is in the east, and then they have a small western balancing authority in the Asheville/Hendersonville region that's about 1100 megawatts, as a separate balancing area. Duke Energy Carolinas is one contiguous balancing area that sits in between DEP east and DEP west.

COMMISSIONER WHITFIELD: I see. And talk to us, if you could just a second, about the Lee combined-cycle plant, 750 megawatts, in Commissioner Ervin's district. Obviously, that was obviously a lot of generation that was sited. And if you could, share how it's doing and what's going on there.

MR. GLEN A. SNIDER: Certainly. Yes, we brought that plant on-line. It's one of our more efficient – since it's one of the newer gas combined-cycles, it is providing, you know, valuable energy. Again, I, you know, talked about natural gas being under $3 an MMBtu. Well, on a pure variable-cost basis, if I am burning – I'll use $3 because the math is easy. But if I'm burning $3 gas at a 6500 heat rate, I'm under $20 a megawatt-hour, which is, you know, really low-cost production for Duke Energy Carolina customers, and it's a good asset.

COMMISSIONER WHITFIELD: Thank you.

That's all I have, Mr. Chairman.

VICE CHAIRMAN ELAM: Commissioner Ervin?

COMMISSIONER ERVIN: Thank you, Mr. Chairman.

Glen, I was interested in the presentation. Excellent job with the overview. Thank you for coming today. I want to dig a little bit deeper into just some things that I don't know, and I'm trying to pick your brain a minute. The pumped storage unit that is in operation, it seemed to work fairly well. Are there any other sites or locations within your service area that would qualify for consideration for a pumped storage

facility to deal with peak demand?

MR. GLEN A. SNIDER: Yes, we have — you know, Jocassee and Bad Creek are two of the bigger pumped storage facilities in the nation, and they are extremely valuable assets for Duke Energy Carolinas, Duke Energy as a whole.

We are — probably our most near-term ability to get a little bit more out of those — and it's in the IRP; I should've put it as a bullet in here — is we are upgrading those, as part of our maintenance cycle. We're able to put in what's called larger runners. And so we expect to get — I believe it's in the neighborhood, subject to check, of about 260 extra megawatts of pumped storage through uprates to those facilities. So that's our first sort of low-hanging fruit, because it doesn't involve the creation of new reservoirs.

As I understand it, there is a potential to expand those facilities and the reservoirs at those facilities, add additional powerhouse, and that's something that, if the economics came to fruition on, you know, something we continue to look at could provide potential in the future.

COMMISSIONER ERVIN: So that's kind of in the — it's on the board, but it's not under immediate

consideration, so to speak?

MR. GLEN A. SNIDER: That's right.

COMMISSIONER ERVIN: Okay. And the other question, long-term, because I know we don't really have any immediate plans for wind-power turbines out on our — the Atlantic shelf, but I didn't even see it in the long-term projections. Is that something that's at all, in the long-term future, going to be a part of the mix, or not?

MR. GLEN A. SNIDER: No, I think there have been — the reason it's not in the mix now is the technology — the siting challenges in the Carolinas is pretty tricky, right? You know, there's two — you've got to go where the wind is, as we like to say, and the wind is on the coast and in the mountains. And right now, you know, the coast is difficult to site, with military, estuaries, there's a lot of tourism. So it's difficult to site right on the coast.

You pointed out offshore. Costs need to come down a little bit more, and you've got to solve the transmission — not just to get it onshore but then to move it onshore to where the load is. So there's both an onshore and an offshore transmission component that you have to solve.

But what I will say is that, you know, we do keep very close tabs on it, and as technology — some of the interesting developments — matter of fact, I was just reading an article, I think, or talking to someone about how the hub heights are getting so much higher, through material sciences, that you can now come further — the higher you go, the windier it is. And so if you can come inland and still get good wind production by going higher, that may present a potential for siting that heretofore has not been there in the Carolinas.

So, a long-winded answer to your question, but I do think there is long-term potential as these hub heights get higher and open up siting opportunities that perhaps aren't there today.

COMMISSIONER ERVIN: And you still own the property up at — was it Cherokee, where you abandoned a nuclear plant years ago? I'm trying to — where is that? Cherokee County?

MR. GLEN A. SNIDER [DUKE ENERGY]: I am not — I don't — I believe we do, but I do not know for sure.

COMMISSIONER ERVIN: I was just curious. Any plans for that particular property? Is it something that you could utilize, going forward?

MR. GLEN A. SNIDER: I don't have any details on that. I apologize, Commissioner Ervin.

COMMISSIONER ERVIN: Thank you.

VICE CHAIRMAN ELAM: Commissioner Hamilton?

COMMISSIONER HAMILTON: Thank you, Mr. Chairman.

If I might follow up a little bit on what Commissioner Ervin was talking about, those of us that are in the Pee Dee and on the coast think the mountains are the perfect place for the wind.

[Laughter]

I think you'll find public opinion at the coast is not too high on that.

One question: I know years ago, when I was first researching the idea of becoming a commissioner, merchant power was the big thing under PURPA at that time, and today it appears to be that solar is doing that. How competitive now is solar?

MR. GLEN A. SNIDER [DUKE ENERGY]: Yeah, no, that's a great question, and, you know, I think that's the benefit of the competitive process that we spoke about, I think earlier in the week, about ensuring that you have a competitive process that makes sure that solar is on par. You know, one of

the things that wasn't mentioned, in the competitive procurement process that we run at Duke, it doesn't have an unlimited path — I mean, it doesn't say, "Take this solar at unlimited price." It says it must come in under the avoided-cost cap, and then to do that, you need to compete to get that generation.

So, you know, I think costs are dropping for solar and storage, which helps. But as I pointed out earlier, so are natural gas prices, and it — so I think solar is competitive for the energy, but the more of that you add and the lower gas prices become, I think it starts to become more an equilibrium, and it places sort of a natural limit on the amount that will be competitive before you need to diversify to another resource.

So right now, it's really fairly competitive to traditional energy, if procured through competitive procurement.

COMMISSIONER HAMILTON: On a five-year contract, has an investor in solar — does he have the opportunity to be able to survive under a five-year contract?

MR. GLEN A. SNIDER: You know, I know there's a lot of debate around the term and financing and

what's the appropriate term. And many states have very short-term agreements and others have longer-term, so there's diversity even amongst the jurisdictions. Several states aren't even five years, while there are a handful of states that have gone 10, 15, 20. So I know there's a big debate among that, within the different state jurisdictions.

My read on that, particularly, is, PURPA does not require you to obtain financing. In other words, you don't just pay whatever price or give whatever term so this can happen, or else you would violate the indifference principle. But you need to have financeable terms and conditions so that it's very clear you get this fixed price for five years. We have the obligation to take it in year six. Year six, the price will be reset, but you're going to have a guaranteed offtake, you're going to have financeable terms and conditions that allow you to have a home for your energy; it just doesn't fix the price.

So I think it's a question of who wears the risk, in your example, for years six through ten. Is that risk worn by consumers? Or is that risk worn by the developer? And that's a decision that

each of the commissions have taken different positions on.

COMMISSIONER HAMILTON: Okay. I appreciate that information. And I appreciate you giving us a list of your potential retirements in the future, and I feel sure we'll have an opportunity to discuss the replacement for those retirements and the location, so...

MR. GLEN A. SNIDER: We will have a certain discussion around that, I am sure. I agree with you, Commissioner.

COMMISSIONER HAMILTON: Thank you, very much. You always do a good job, Mr. Snider, and we leave here a better Commission because of your presence, and we thank you for it, sir.

MR. GLEN A. SNIDER [DUKE ENERGY]: Thank you, so much, Commissioner Hamilton.

VICE CHAIRMAN ELAM: Okay. I guess I've got a couple, Mr. Snider. I'm looking at your Slide 23, 24, and the growth of the natural gas percentage, as far as the capacity mix and the energy mix. Fair to say that that is assuming a very stable price of natural gas for – how many years?

[WHEREUPON, at 11:33 p.m., Commissioner Whitfield departs the proceeding.]

MR. GLEN A. SNIDER: Yeah, you know, I think it is – a couple of quick points on that. That's why we do stress the portfolio, "How would this look under a high- and a low-gas," and stress it. But, quite honestly, those stresses now are "Hey, if $2.80 gas goes to $3.80 or $4"; it's no longer does $12 gas go to $16. And I think the stability of the supply source, through shale gas, has fundamentally changed the market. So it is relatively – a percentage change – I guess one of the things to think about is, a 10 or 15 percent change in natural gas prices used to mean $1 or $1.50 an MMBtu. Now a 10 percent change in natural gas prices is 28 cents an MMBtu. So it's not just the percentage volatility, but it's the new lower price levels where that volatility is no longer as impactful on consumers, because it still is a relatively cheap form of generation.

I guess my last point on that is, you know, is we – over the last couple of years, we've been looking more than just two years out; we've been looking ten years out at the markets. We've actually done a few purchases, just to test the liquidity – not as part of our normal gas procurement program, but to test the liquidity and

to validate price levels in the market. And for the last two years, we've been able to secure ten years of natural gas at under — at $3 or under, routinely, over a two-year period. So that's provided me, also, a little bit of comfort in the long-term stability of gas prices.

VICE CHAIRMAN ELAM: Okay. And I think you just answered my next question. You have been able to get ten-year contracts for gas?

MR. GLEN A. SNIDER: Yeah. You know, a lot of times people will say it's not liquid that far out, because they're just looking at the New York Mercantile Exchange, which is where more of the short-term futures contracts trade, but brokers, gas brokers, will certainly — or financial institutions, that will sell you the financial contracts on gas — will go further out on that in bilateral forwards, as opposed to the futures. So if you go into the forwards market, do forwards contracts, you can find liquidity out ten years.

VICE CHAIRMAN ELAM: And I usually, at this point, come back to my maybe unlikely scenario that we have a major fracking-related earthquake in the United States, and what that would do to the price of gas. And as far as planning, where would you

be, as far as capacity and energy mix, if you had the price of gas go towards $15 again?

MR. GLEN A. SNIDER: Right, and, you know, I — there's always that black-swan or what-if scenario that you do need to be cognizant of. You know, right now, you know, while coal is a small portion, at least at this point in time, we still do have 10,000 megawatts of coal. The reason that energy chart right there is such a small sliver is they run at a very low capacity factor these days, at gas prices. If that were to happen tomorrow, you would probably revert back to where coal was before, and they would become your intermediate and base load, and you would rely on gas as a peaking resource until you had time to bring on either more non-traditional resources — efficiency, DSM, renewables, longer-term SMR you would relate to that. That is part of the benefit of having a diverse capacity mix right now, is we can switch back and forth between the two.

VICE CHAIRMAN ELAM: I think that I was just seeing in one of these charts coal going down to just such a small percentage — I think I'm looking at page 24, the 2033, you've got coal down to 8 percent — and if you were to run into issues there,

how quickly coal may be able to fill that gap?

MR. GLEN A. SNIDER: Certainly, you know, we're not projecting the ability to build any new coal. So let me, you know, be clear. But prior to any of the coal retirements, that 8 percent – well, that 8 percent does reflect some future retirements at the end of the planning horizon, but we still have – the reason it's 8 percent is its energy. If you go back one slide, coal is about, in DEC, 18 percent of the capacity mix. You would take that 18 percent capacity and, until you had time to adjust to the gas prices, you would start dispatching that. And that 8 might grow to 25 or 30 again, until you had time to displace that economically with other resources.

VICE CHAIRMAN ELAM: And you would have the coal supply to be able to do that, on hand?

MR. GLEN A. SNIDER: We have the rail contracts in place and the mines. You know, the question of where's the industry going to be ten years from now, in terms of their ability to ramp up, is a legitimate question.

VICE CHAIRMAN ELAM: Okay. I'm still looking at page 24. And either for energy or non-nuclear energy, the growth in renewables between 2019 and

2033 doesn't seem to be that much, as a percentage. Can you talk to me about that?

MR. GLEN A. SNIDER: Right, renewables on the non-nuclear side growing. A lot of that — well, two things that — I've had to look into this a lot myself — is, one, the system is growing, right? So that need, while it's only 1 percent, is a lot of megawatts and megawatt-hours each year, so your renewables become part of a bigger pie.

What we're showing right now is, you know, the predominant renewable — given the discussion we just had, both wind and solar, right? — has been — unlike a lot of areas in the country where maybe they show a bigger percentage, there's two things: One is, they have wind; and they use less electricity. So the Southeast uses about twice the electricity per capita of anywhere else in the country. We're the only ones that both heat and cool with electricity as our dominant source of heating and cooling, and we have more heating and cooling degree days than just about anybody. So I always get compared to "Look what California's doing," or, "Look what the Northeast..." and you look at these percentages. And I always remind people, they use 600 kilowatt-hours or 500

kilowatt-hours a month. We use 1200. And so that wind in the Midwest, if I'm only using 600 kilowatt-hours a month in Michigan or Indiana or Illinois, is a much bigger percentage than solar. Wind up there is 50 percent utilization rate capacity — maybe not that high; that's more panhandle wind in Oklahoma and Texas. But you're still 40 percent, you know, capacity factor for wind in the Midwest. Solar is more of a 25 percent. With some of the over-paneling, you might get in the high 20s or even 30, but it's a much smaller utilization rate against a much bigger denominator.

So we have much more consumption here in the South, and we have a resource that doesn't produce as much as wind does. And as we've shown, even though we're national leaders in solar, and we're growing — you know, we project to grow to, I think it's over — I went back — over 8000 megawatts collectively, between DEC and DEP — the fact that the utilization rate on that solar, the capacity factor of that solar, is so much less than other resources, like wind, and the fact that the denominator is so much bigger, and growing, is why that percentage looks smaller than perhaps when

you're at a NARUC conference and you see people talking about what's happening in other parts of the country. Well, they have a different resource, as well as a different denominator, so their percentage looks bigger than perhaps what you're seeing here, even though we are national leaders in the amount of solar being added.

VICE CHAIRMAN ELAM: Okay. And I think your Slide 9 may answer this, because it does reference electric vehicles. But all the capacity projections you've got in the back, those take into account projections of electric vehicle growth?

MR. GLEN A. SNIDER [DUKE ENERGY]: They do. And, you know, that's a – you know, that is an interesting area where there is a divergent opinion on the rate of adoption of electric vehicles. We use sort of a consensus view; I think we get ours from EPRI. It's sort of in the middle of the pack on electric vehicles. There are others in the industry that say where maybe we're saying we're going to get to 3 percent penetration of EVs in a decade, others say maybe, on the high end, 6 or 7, right? And so, depending on how the EV market plays out, that could have an upward demand on both demand and energy. But that is – you know, that's

sort of the outlier view. I think our forecast takes more of a consensus view.

VICE CHAIRMAN ELAM: Could that be balanced a little bit, as far as capacity needs, by when people would commonly charge electric vehicles off-peak, whether it's at night or sometime during the middle – you know, the early afternoon?

[WHEREUPON, at 11:42 p.m., Commissioner Ervin departs the proceedings.]

MR. GLEN A. SNIDER: Right. I think that'll – you know, I've seen different discussions on how that's going to evolve in the marketplace. I certainly think there's a potential for that, if the structures are in place that incentivize people to charge off-peak.

VICE CHAIRMAN ELAM: That's all I have. I seem to have lost that end of the bench.

[Laughter]

So, thank you. I appreciate the presentation, and you may step down.

MR. GLEN A. SNIDER: Vice Chairman, thank you, so much. Thanks for having us today.

VICE CHAIRMAN ELAM: If there's not anything else, we're adjourned.

[WHEREUPON, at 11:45 p.m., the

proceedings in the above-entitled matter were adjourned.]

C E R T I F I C A T E

I, Jo Elizabeth M. Wheat, CVR-CM-GNSC, Notary Public in and for the State of South Carolina, do hereby certify that the foregoing is, to the best of my skill and ability, a true and correct transcript of all the proceedings had in an allowable ex parte briefing communication held in the above-captioned matter before the PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA;

IN WITNESS WHEREOF, I have hereunto set my hand and seal, on this the 28th day of October, 2018.

Jo Elizabeth M. Wheat, CVR-CM/M-GNSC
Hearings Reporter, PSC/SC
My Commission Expires: January 27, 2021.